

1 **DIRECT TESTIMONY OF**

2 **JOSEPH M. LYNCH**

3 **ON BEHALF OF**

4 **SOUTH CAROLINA ELECTRIC & GAS COMPANY**

5 **DOCKET NO. 2014-246-E**

6
7 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

8 A. My name is Joseph M. Lynch, and my business address is 220 Operation
9 Way, Cayce, South Carolina.
10

11 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?**

12 A. I am employed by SCANA Services, Inc. ("SCANA Services") as Manager
13 of Resource Planning.
14

15 **Q. PLEASE DESCRIBE YOUR DUTIES RELATED TO RESOURCE**
16 **PLANNING IN YOUR CURRENT POSITION.**

17 A. I am responsible for managing the department that produces South Carolina
18 Electric & Gas's ("SCE&G" or "Company") forecast of energy, peak demand and
19 revenue. I am also responsible for developing the Company's generation
20 expansion plans and overseeing the Company's load research program.

1 Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND
2 PROFESSIONAL EXPERIENCE.

3 A. I graduated from St. Francis College in Brooklyn, New York, with a
4 Bachelor of Science degree in mathematics. From the University of South
5 Carolina, I received a Master of Arts degree in mathematics, an MBA, and a Ph.D.
6 in management science and finance. I was employed by SCE&G as a Senior
7 Budget Analyst in 1977 to develop econometric models to forecast electric sales
8 and revenue. In 1980, I was promoted to Supervisor of the Load Research
9 Department. In 1985, I became Supervisor of Regulatory Research where I was
10 responsible for load research and electric rate design. In 1989, I became
11 Supervisor of Forecasting and Regulatory Research, and in 1991, I was promoted
12 to my current position of Manager of Resource Planning.

13
14 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE
15 COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

16 A. Yes. I have previously testified on a number of occasions before this
17 Commission.

1 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 **A.**The purpose of my testimony is to discuss the components of value that
3 SCE&G's electric system receives when customers operate a net metered
4 distributed energy resource ("DER") that is designed to meet a portion or all of
5 their requirements for energy and capacity. I also discuss SCE&G's approach for
6 quantifying those benefits. South Carolina Code Ann. §§ 58-40-10 *et seq.* ("Net
7 Metering Statute" or "Statute") requires the Commission to issue an order
8 establishing a methodology for determining charges or credits that should be
9 applied to a customer-generator's bill when they are operating under net metering
10 tariffs. Those charges or credits are referenced in Section ~~58-40-20(F)~~(1) and (2)
11 of the Net Metering Statute. Section 58-40-20(F)(2) and (4) reference the
12 methodology for computing those credits. My testimony discusses the
13 components of that methodology that relate to the value of DER resources in the
14 context of the order that the Commission is required to issue under Section 58-40-
15 20(F)(4) of the Net Metering Statute.

1 Q. WHAT ARE THE COMPONENTS INCLUDED IN THE NET VALUE OF
2 ~~A DER~~?

3 A. My testimony supports the proposal that the Commission approve a
4 methodology that includes 11 components to assess the benefits and costs of DER
5 resources operated under net metering tariffs. This methodology is set forth in the
6 settlement agreement (the "Settlement Agreement") that SCE&G entered into with
7 the South Carolina Office of Regulatory Staff and others. That Settlement
8 Agreement contains a methodology that uses the 11 components listed on
9 Attachment A to that Agreement to determine the net benefit of DER generation.
10 The components are as follows:

11 **Components of Value for Net Metered DER**
12 **Net Metering Methodology**

- 13
14 1. +/- Avoided Energy
15 2. +/- ~~Energy~~ Losses/Line Losses
16 3. +/- ~~Avoided~~ Capacity
17 4. +/- ~~Ancillary~~ Services
18 5. +/- T&D Capacity
19 6. +/- ~~Avoided~~ Criteria Pollutants
20 7. +/- ~~Avoided~~ CO₂ Emission Cost
21 8. +/- ~~Fuel~~ Hedge
22 9. +/- ~~Utility~~ Integration & Interconnection Costs
23 10. +/- ~~Utility~~ Administration Costs
24 11. +/- Environmental Costs
25 **= Total Value of Net Metered DER**

26 I will discuss each of these components in turn.
27

1 **Q. WHAT IS THE RELATIONSHIP BETWEEN YOUR TESTIMONY AND**
2 **THE SETTLEMENT AGREEMENT?**

3 **A.** SCE&G supports the Settlement Agreement and the intent of my testimony
4 is to support the Settlement Agreement in all respects. My testimony is not meant
5 to speak for anyone but SCE&G. I would not expect that all parties to the
6 Settlement Agreement would agree with the Company's views.

7
8 **Q. IN YOUR VIEW, HOW WOULD THE 11 COMPONENTS BE APPLIED**
9 **TO MEET THE REQUIREMENTS OF THE NET METERING STATUTE?**

10 **A.** When customers install DER resources, they reduce what they pay to the
11 Company under established rates, which are set at a level calculated to recover the
12 Company's cost to serve each customer class. The reduction in what the DER
13 customer pays may or may not reflect the costs the Company avoids as a result of
14 the customer installing the DER resource. The 11 components identified in the
15 Settlement Agreement represent the categories of the Company's costs that may
16 change as a result of the customer meeting part of its needs through its DER
17 resource(s), and providing energy and capacity to the system. Comparing the
18 reduction in the customer's bill to the change in the Company's costs of serving
19 that customer tells you whether the customer is paying too much or too little under
20 the net metering rate.

1 **Q. SHOULD THE LIST OF COMPONENTS IN THE NET METERING**
2 **METHODOLOGY INCLUDE SOCIAL COMPONENTS SUCH AS**
3 **ECONOMIC DEVELOPMENT OR OTHER EXTERNALITIES?**

4 **A.**No, SCE&G believes only known and measurable costs that would appear
5 in a revenue requirements study should be included in the design of rates. Costs
6 that are not known and measurable should be avoided in rate calculation. This
7 ensures that ratemaking is based on objective, verifiable costs, not conjecture.
8 This is as important for net energy metering rates as it is for any other rates. Any
9 benefits calculated using the settlement methodology that are not direct cost
10 savings experienced by the Company, like reduced fuel costs or capacity costs,
11 become costs that must eventually be paid by other customers. If hypothetical,
12 contingent or uncertain costs are included in the calculation of DER benefits, then
13 non-DER customers are at risk for paying for costs that can never be objectively
14 verified, and benefits that never materialize.

1 **Q. SHOULD A DIFFERENT VALUE OF A DER BE EXPECTED FROM**
2 **EACH UTILITY EVEN WHEN USING THE SAME LIST OF**
3 **COMPONENTS?**

4 **A.** Yes, the value of a DER, which is based on avoided costs, is utility specific
5 and depends on the utility's mix of generation plants, its mix of customers and
6 their usage patterns and its resource plan for the future.

7
8 **Q. THE FIRST COMPONENT OF THE NET METERING METHODOLOGY**
9 **IS "AVOIDED ENERGY" COSTS. WHAT ARE AVOIDED ENERGY**
10 **COSTS AND HOW DOES SCE&G COMPUTE THEM?**

11 **A.** Avoided energy costs are the costs of the incremental energy that SCE&G
12 would be required to generate were it not for the energy generated by the DER and
13 consumed by the customer or provided to the grid. The methodology used by
14 SCE&G to estimate avoided energy costs is essentially the same one it has been
15 using to satisfy the requirements of the Public Utilities Regulatory Policies Act
16 since its passage in 1978, and it is the methodology used by most, if not all,
17 electric utilities. The methodology calculates the change in production costs
18 between a base case and a change case using very carefully constructed computer
19 programs that model the commitment of generating units to serve load hour-by-
20 hour over the course of a full year. These programs account for all of the costs

involved in meeting load, including fuel and environmental costs (including reagents and emission allowances), start-up and ramping costs (which accounts for the increased fuel consumption as steam plants are brought up to operating temperature), and variable operation and maintenance costs. The base case is defined by SCE&G's existing fleet of generators and the hourly load profile to be supplied by these generators. The change case is the same as the base case except the hourly loads are reduced by 100 megawatts in each hour.

Using software to simulate the dispatch of its generation fleet, SCE&G estimates the production costs that result from serving the base case load and the change case load. The reduction in costs from the base case to the change case represents the avoided costs associated with a 100 megawatt ("MW") reduction in load. The costs are accumulated into four time-of-use periods composed of two seasons, peak (PS) and off-peak (OS), and two daily periods, peak hours (PH) and off-peak hours (OH).

Exhibit No. ____ (JML-1) contains the definition of these time periods and the following table shows the number of hours within each time period and the approximate percent of solar generation within each. The solar percentages are used to calculate an average solar energy value for the year.

Time Periods	PSPH	PSOH	OSPH	OSOP	TOTAL
Hours	1056	1872	2064	3768	8760
Solar Energy %	25.8%	16.8%	27.4%	30.0%	100.0%

The South Carolina Generation Tax of 0.5 mills per kilowatt-hour and a working capital adjustment of about 4.4% are added to the final energy value as well as an adjustment for degradation in the output of solar facilities over time.

Q. HOW MUCH ENERGY WOULD A TYPICAL SOLAR INSTALLATION PRODUCE IN SOUTH CAROLINA?

A. The energy output of a solar facility naturally depends on the installation and such factors as whether the panel tracks the sun or are fixed and, if fixed, at what angle and in which direction the panels face and how much shading occurs and several more factors. The table below summarizes the output of certain solar facilities on SCE&G's system. The "PR-1 Average" in the table represents the metered solar generation of approximately 15 customers currently on the Company's PR-1 Rate under the buy all/sell all option. The "Boeing Generator" refers to the Company's \$13 million, ten acre solar generation facility, which is located on the roof of The Boeing Company's North Charleston production facility.

	Peak Output (kW AC)	Annual kWh	Load Factor (AC Rating)
PR-1 Average	5.8	9,115	17.9%
Boeing Generator	2,419.2	3,409,956	16.1%

1 Discussions concerning the output of solar facilities can become confused if
2 it is not made clear whether the direct current ("DC") nameplate of the facility is
3 used as the reference size or the actual alternating current ("AC") peak output.
4 When the size or cost per kilowatt ("kW") is reported, it is typically based on the
5 DC rating. However, the peak AC output can be as much as 20% less. This is due
6 to losses in the wiring and connections among other things as well as losses that
7 occur in the conversion of the DC output to AC power.

8
9 **Q. HOW IS THE SECOND COMPONENT "ENERGY LOSSES/LINE**
10 **LOSSES" USED IN THE METHODOLOGY?**

11 **A.** The 10 components, other than the energy losses/line losses component,
12 represent costs that are stated at the generator busbar, *i.e.*, at the point of power
13 generation. Because the DER typically generates energy on the distribution
14 system, the Company will avoid having to generate not only that amount of energy
15 but also the line losses associated with delivering it to the distribution system.
16 SCE&G computes average loss factors to account for these losses.

17
18 **Q. HOW DOES SCE&G CALCULATE THE NEXT COMPONENT,**
19 **"AVOIDED CAPACITY" COSTS?**

A. SCE&G uses a difference in revenue requirements (“DRR”) methodology to calculate avoided capacity costs. Using the resource plan in its latest Integrated Resource Plan (“IRP”), which is filed with the Commission, or an updated resource plan if appropriate, SCE&G calculates the incremental capital investment related revenue required to support the existing resource plan and then develops a changed resource plan based on the assumption of a 100 MW capacity purchase at zero cost over the 15-year IRP planning horizon. The change in revenue requirements over the 15-year period between the two resource plans is associated with the 100 MW purchase and is stated as an average cost per kw-year.

Since the output of a solar facility declines throughout the afternoon, only a percentage of its capacity can be relied upon as firm capacity to serve SCE&G’s peak loads. To estimate this percentage, SCE&G analyzes the expected solar output during its critical summer peak hours of 2 p.m. to 6 p.m. (“Critical Hours”) during the weekdays of June, July, and August. The following table compares the maximum solar output to the average hourly output during these Critical Hours for all PR-1 customers and SCE&G’s solar facility at Boeing.

Development of the Firm Capacity Ratio for a Solar Facility				
Source	Year	Maximum Output (kW)	Average Output Critical Hours (kW)	Ratio
All PR-1 Customers	2012	3.3	1.4	0.424
	2013	5.8	2.5	0.431
Boeing Generator	2012	2448.0	1090.2	0.445
	2013	2419.2	965.5	0.399
Average				0.42

1 Based on these results, SCE&G will assign 42% of its avoided capacity costs to
2 the AC capacity of a solar facility.

3 **Q. DOES SCE&G HAVE AN ESTIMATE FOR THE NEXT COMPONENT**
4 **"ANCILLARY SERVICES"?**

5 A. Ancillary services refer to the need to balance the load and generation on
6 the system and include operating reserves, both spinning and non-spinning;
7 frequency regulation; and voltage control. DER resources, specifically solar
8 resources, represent intermittent resources that are not dispatchable. With the
9 addition of a DER to the grid, SCE&G expects the cost of supplying ancillary
10 services to the system will increase. As a result, SCE&G will assign a zero cost to
11 this component but considers it a place holder subject to future revision and an
12 offset to other potential benefit categories where data is unavailable.

13
14 **Q. HOW DOES SCE&G VIEW THE NEXT COMPONENT, "T&D**
15 **CAPACITY"?**

16 A. "T&D Capacity" refers to capital investment in the transmission and
17 distribution system which serves SCE&G's customers. The transmission and
18 distribution components of T&D must be handled separately. Because of the
19 intermittent nature of solar generation, the relatively small amount of DER
20 generation in total that is expected in the foreseeable future, and the relatively

1 large power flows involved in modeling and sizing the transmission system, it is
2 not clear that SCE&G will avoid transmission investment because of the addition
3 of DER to the system. Therefore, SCE&G will assign a zero cost to this
4 component as a place holder subject to future revision. Similarly SCE&G's
5 avoided distribution costs are zero because a DER is an intermittent power source.
6 When SCE&G's engineers design a distribution circuit, they must plan for the
7 worst possible circumstances; in particular, they must plan for when the DER is
8 not supplying power. The distribution line must carry the load both when the
9 DER is generating and when it is not because of weather related factors or because
10 DER resources are off-line. Adding a DER to a distribution circuit may increase
11 costs because of the potential for back flows at the substation, the need for bi-
12 directional switches, or the need for more voltage control. Some of these costs
13 may be more properly labeled integration costs, which is another component of the
14 net metering methodology.

15
16 **Q. HOW DOES SCE&G HANDLE THE NEXT COMPONENT, "AVOIDED**
17 **CRITERIA POLLUTANTS"?**

18 **A.** The cost of emitting or controlling criteria pollutants are part of the variable
19 cost of dispatching the system and are included in the avoided energy component.

1 **Q. DOES SCE&G INCLUDE A COST RELATED TO AVOIDED CARBON**
2 **DIOXIDE ("CO₂") EMISSIONS?**

3 A. Today, there are no laws or regulations governing CO₂ emissions, and as a
4 result, there are no costs associated with emitting CO₂. Therefore, SCE&G will
5 set the value of this component of the net metering methodology to zero at this
6 time. However, SCE&G anticipates adding a cost in the future when CO₂ laws or
7 regulations are implemented and result in a cost to SCE&G's customers.

8
9 **Q. IS THERE A VALUE TO FUEL HEDGING FROM DER?**

10 A. Fuel hedging is a means to reduce fuel price volatility but there is a cost to
11 engage in fuel hedging which tends to increase the cost of the fuel being hedged.
12 SCE&G does not engage in financial fuel hedging and therefore, does not incur
13 fuel hedging costs. Some have suggested there may be a benefit to fuel hedging in
14 spite of the absence of any direct cost reduction. In SCE&G's case, DER provides
15 no value in reducing fuel volatility for the following reasons:

16 1. Approximately 70% of electric cost is not related to fuel.

17 2. In 2013, natural gas purchases accounted for approximately 28% of fuel
18 costs.

1 3. Over 90% of natural gas is consumed at combined cycle plants which have
2 firm transportation ("FT") contracts. FT contracts provide a partial hedge
3 against gas price volatility.

4 4. Therefore, based on the above, over 90% of electric cost is not related to
5 gas prices and an additional 8% is partially hedged by FT contracts leaving
6 only 2% subject to full market volatility.

7 5. All fuel cost is subject to the fuel clause which spreads volatility over time.

8 6. Normal weather related volatility will easily outweigh any remaining
9 volatility.

10 Consequently, SCE&G assigns zero value to the fuel hedging component of DER.

11
12 **Q. PLEASE EXPLAIN THE UTILITY INTERCONNECTION AND**
13 **INTEGRATION COSTS COMPONENT OF THE NET METERING**
14 **METHODOLOGY.**

15 A. The utility interconnection costs include the addition of an extra meter so
16 that power flows can be measured in both directions with special metering such
17 that the flows can be measured on a 15-minute integrated basis. The utility
18 integration costs involve the potential need to add equipment to the distribution
19 circuit to maintain voltage within regulated limits as well as to manage backflow
20 issues on the substation. At this time, SCE&G envisions that it will use a zero

dollar entry when it files its NEM tariff and will consider adding a cost as the NEM population expands.

Q. PLEASE EXPLAIN THE UTILITY ADMINISTRATIVE COSTS COMPONENT OF THE NET METERING METHODOLOGY.

A. The utility administrative costs include the software systems required to manage 15-minute interval data and the billing oversight to verify the rendering of a bill. It also includes the engineering costs to monitor the distribution circuits for voltage issues and the management oversight of the NEM program. At this time SCE&G does not have an estimate of these costs but will revisit this matter when the NEM tariff is filed with the Commission.

Q. PLEASE EXPLAIN THE ENVIRONMENTAL COSTS COMPONENT OF THE NET METERING METHODOLOGY.

A. The component of "Environmental Costs" refers to any appropriate environmentally related costs that were not already included in other net metering methodology components. At present, all environmental costs are quantified in the other specific components of the methodology.

Q HAS SCE&G QUANTIFIED A PRELIMINARY VALUE FOR A NET METERED DER USING THIS METHODOLOGY?

A. Yes, the table below shows a preliminary value for a net metered DER. Two columns of numbers are shown: one for the current value and one for the value over the IRP planning horizon. One purpose of this exercise is to set current rates. In doing so, it is important to recognize that a DER installed today will result in the avoidance of a certain amount of current and future costs. Unless SCE&G adjusts its rate schedules to reflect this reality, the Company will not recover the necessary costs to operate its electric system. . The difference between these two columns of numbers represents the future benefits of DER and would be subject to collection under S.C. Code Ann. § 58-40-20(F)(6).

Total Value of Net Metered DER (\$/MWh)		
Current Period	IRP Planning Horizon (15 Year Levelized)	Components
\$37.84	\$38.33	Avoided Energy Costs
0	9.04	Avoided Capacity Costs
0	0	Ancillary Services
0	0	T&D Capacity
0	0	Avoided Criteria Pollutants
0	0	Avoided CO2 Emission Cost
0	0	Fuel Hedge
0	0	Utility Integration & Interconnection Costs
0	0	Utility Administration Costs
37.84	47.37	Sub-total
1.67	2.09	Line Losses @0.9578
\$39.51	\$49.46	Total Value of Net Metered DER

1 Before filing an actual NEM tariff rate, SCE&G expects to update these figures.

2
3 **Q. WHAT IS SCE&G REQUESTING OF THE COMMISSION?**

4 A. SCE&G respectfully requests that the Commission approve the Settlement
5 Agreement entered into by the settling parties in this proceeding and the net
6 metering methodology set forth in the Settlement Agreement.

7
8 **Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

9 A. Yes it does.

1 **Definition of On and Off Peak Periods**

Exhibit No. _____ (JML-1)

2
3 **PEAK SEASON**

4 **Months of June, July, August, and September:**

5 **Peak Hours:** Monday through Friday

6 10:00 AM to 10:00 PM

7 (Excluding holidays)

8 **Off-Peak Hours:** All hours not specified as Peak Hours.

9 **OFF-PEAK SEASON**

10 **Months of May and October:**

11 **Peak Hours:** Monday through Friday

12 10:00 AM through 10:00 PM

13 (Excluding holidays)

14 **Off-Peak Hours:** All Hours not specified as Peak Hours.

15
16 **Months of January, February, March, April, November, and December:**

17 **Peak Hours:** Monday through Friday

18 6:00 AM to 1:00 PM and 5:00 PM to 10:00 PM

19 (Excluding holidays)

20 **Off-Peak Hours:** All Hours not specified as Peak Hours.